Decision **PROPOSED DECISION OF ALJ MALCOLM** **(Mailed 4/26/2005)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Gas Rates and Tariffs to be Effective July 1, 2005. (U 39 G)	Application 04-07-044 (Filed July 30, 2004)

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INTERIM ORDER

Summary of Decision

This order resolves all outstanding issues except future allocation of California Alternate Rates for Energy (CARE) costs in this application of Pacific Gas and Electric Company (PG&E) to allocate certain costs among various rates for natural gas services and to establish gas throughput forecasts upon which to base those rates.

This decision adopts several settlements filed by the parties on various issues and resolves three other outstanding disputed matters. As a result of this order, PG&E's residential gas rates will increase by about 1.2% per therm. Small commercial rates will decrease very marginally by 1%. Large commercial core rates will fall by 5% and the rates of large commercial customers that take transportation only will fall by 22.7% as a result of partial deaveraging ordered today. Industrial transportation rates increase by 1.9% for transmission level service and distribution rates increase by 3.6%.

1. Background

PG&E filed this "Biennial Cost Allocation Proceeding" (BCAP) application on July 30 2004 seeking changes in rates, revenue allocations, and rate design for natural gas sales and services. PG&E proposes allocating $1.076 billion among different customer allocations. Included in this amount, PG&E proposes a revenue increase of $12.8 million. PG&E's application proposes that all subject rates take effect on July 1, 2005. Decision (D.) 01-11-001 was PG&E's last BCAP decision for rate changes that became effective January 1, 2002. Although the Commission has normally processed BCAPs every two years, PG&E explains it delayed filing this application because of intervening events, including the energy crisis and PG&E's bankruptcy proceeding in federal court.

Three parties filed formal protests to this application: the Commission's Office of Ratepayer Advocates (ORA), The Utility Reform Network (TURN), and the California Cogeneration Council (CCC). The California Manufacturers and Technology Association (CMTA), the Indicated Producers (IP), the Western Mobilehome Community Housing Association (WMA), West Coast Gas Company (West Coast), and Clean Energy either commented on PG&E's proposals, made counterproposals, or presented proposals of their own.

The Commission held five days of evidentiary hearings in this proceeding. Parties filed briefs on March 23, 2005 and reply briefs on April 8, 2005 and the proceeding was submitted. No party requested final oral argument.

2. Proceeding Issues

The issues addressed in this proceeding were described in PG&E's application generally as addressing and resolving:

- Gas throughput forecasts for core and noncore customers;
- Marginal distribution and customers' costs;
- Revenue requirement for gas costs, including special programs; and
- Revenue allocation and rate design.

With a few exceptions, the scope of this proceeding is limited to the allocation of costs to PG&E's gas distribution customers and the rates resulting from those allocations. PG&E's costs of providing gas distribution service were generally addressed in PG&E's general rate case decision, D.04-05-055 in Application (A.) 02-11-017. The Commission addressed PG&E's gas transmission and storage rates in D.04-12-050 in A.04-03-021.

Many of the proposals included in PG&E's application would affect only a portion of PG&E's gas customers. Representatives of affected parties settled many of the issues as we describe below. No party has opposed any of the settlement agreements presented in this proceeding.

We review all agreements, settlements and stipulations in this proceeding pursuant to Rule 51.1(e) which provides that, prior to approval, the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest."

The parties did not reach agreement on three significant issues:

1. Allocation of costs for the California Alternate Rates for Energy (CARE) surcharge to fund a rate discount for low-income customers. PG&E proposes to change the existing allocation method in a way that would increase rates to core customers by $21 million;
2. Allocation of costs assigned to gas ratepayers for the self-generation incentive program (SGIP) adopted in D.01-03-073 in Rulemaking (R.) 98-07-037. CCC / CMTA propose to change the existing allocation method in a way that would increase core customer allocations by $7.2 million; and
3. Long run marginal costs to be used to calculate rates for various customer classes. PG&E proposes changes to the existing method for allocating gas distribution costs to remove the "replacement cost adder," which would increase core customer rates.

This decision modifies PG&E's throughput, makes minor changes to cost allocation and rate design, and approves minor changes to accounting and ratemaking for PG&E's natural gas distribution rates. This decision generally follows past Commission decisions in these areas except where a party or parties have made very compelling showings in favor of changing existing policies or analytical methods. We see no reason to depart from past policy in this implementation proceeding unless circumstances have changed substantially, new information is available, or a party can demonstrate a past order misstates or misapplies facts, policy or analysis.

3. Agreement on Throughput Forecast, Ratemaking and Rate Design Issues

PG&E, TURN, and ORA submitted an agreement during the hearings, which was identified as Exhibit 29. The agreement resolves a number of previously contested issues in this proceeding. No party protested any element of the agreement. PG&E represents that each element of the agreement is a "stand alone" resolution of a discrete issue in the proceeding and was the resolved "on the individual merits of that issue." We therefore consider each issue separately on the merits of the proposed resolution, consistent with the law and the record in this proceeding.

A. Minimum Monthly Residential Transportation Charge

PG&E's application proposed a minimum monthly transportation charge of $5 a month to cover some of the cost to serve residences with extremely low usage during certain months. PG&E states these residences are mostly vacation homes and estimates an actual cost of about $10 a month to serve a customer that does not purchase any gas commodity. ORA was the only party to object to PG&E's proposal, suggesting a $2.50 charge rather than a $5 charge. The Agreement would implement a $3 minimum monthly transportation charge for residential customers.

We concur that a $3 minimum monthly transportation charge is reasonable because PG&E incurs costs even when a customer does not use any gas. The charge will affect mostly second homes during periods of vacancy. Because the charge would primarily affect second homes, it will not cause undue hardship on customers who pay the charge. We find that the charge is reasonable and will adopt it.

B. Gas Baseline Tier Differential

PG&E originally proposed to reduce the differential between the first (baseline) and second tier transportation rates for residential customers. The differential is currently at 70%, which PG&E believes exacerbates high winter bills when most second tier usage occurs. TURN proposed a third baseline period to address this concern.

The Agreement would resolve this issue by adjusting the summer gas baseline allowance to include the month of April. It would also set the gas baseline differential between Tier 1 and Tier 2 for bundled rates at 20% using the weighted average cost of gas filed in the BCAP. This differential would be in effect as long as the transportation rate tier differential between Tier 2 and Tier 1 is no less than 1.6. Therefore, the Tier 2 transportation rate would always be at least 60% greater than the Tier 1 transportation rate.

We agree that this change in the way the residential tiers are designed would mitigate the impacts of winter bills on customers who go into the second tier of usage. It would do so without unduly affecting other customers or other billing elements. We will adopt it.

C. Core Deaveraging

Most energy rates are averaged within classes and in some cases between classes of customers. Averaging simplifies rate design but results in some customers who are relatively inexpensive to serve paying a share of costs associated with customers who cost more to serve. The Commission has permitted PG&E to "deaverage" rates between small commercial and residential customers at a rate of 10% a year. The implication is that core customer rates would rise. In this application, PG&E proposed to accelerate the pace of deaveraging to 20% a year, which ORA and TURN opposed.

The Agreement provides that the pace of deaveraging small commercial and residential rates would continue at the 10% annual rate until PG&E's next BCAP or for up to four years if a BCAP order is delayed. Deaveraging would end after four years absent an additional Commission order.

We concur that accelerating the pace of deaveraging at this time would increase residential rates too much. The gradual approach proposed in the agreement is consistent with past decisions and otherwise reasonable.

D. Core Commercial Rates and Charges

Currently PG&E treats large and small core commercial classes as different customer classes. It proposed in this application to combine them into a single class with ten different rate schedules that would vary according to customer demand. ORA opposed the consolidation and proposed a more gradual phase in of additional rate tiers. The Agreement would retain the existing and distinct rate schedules for large and small commercial customers but add three rate tiers for small commercial customers, making a total of five rate tiers. The Agreement would better reflect the costs of serving small commercial customers and we adopt it.

E. Forecast of Natural Gas Throughput and Customers

PG&E proposed an updated forecast of gas throughput for the BCAP period for each customer class. Each forecast includes a calculation of marginal demand measures and customers. ORA and the CCC question the forecast of gas throughput for electric generation. The Agreement would apply a total throughput of 742,5445 MDth/year for all customer classes. It would increase the throughput forecast for electric generation to 264,913 MDth/year.

The amount adopted in the agreement is a reasonable compromise. PG&E's last BCAP set rates assuming average year throughput forecast for core customers at 306,965 MDth and noncore (Schedule G-NT) customers at 195,336 MDth.

Because of the delays in PG&E's BCAP filing, rates have been based on this throughput forecast since January 1, 2002, although the forecast was adopted assuming a two-year period. Throughput in recent years has decreased substantially. For industrial distribution rates – where PG&E has no balancing account protection – this disparity between the forecast and actual throughput has hurt PG&E's earnings. The industrial distribution throughput adopted in PG&E's last BCAP was 36,681 MDth compared to actual throughput of 26,422 MDth, a disparity which PG&E states caused it to lose about $8 million last year.

Adopting the throughput forecast presented in the Agreement would result in substantially higher rates. Most significantly, electric generation backbone rates more than double as a result of the change in the throughput forecast and electric generation transmission rates increase by almost 6%. However, the forecasts for each customer class that are the subject of the Agreement are reasonable in light of changes in actual throughput in recent years, and we adopt them.

F. West Coast Gas Distribution Transportation Rates

PG&E recently learned that it has erroneously billed two wholesale customers transmission rates even though at least portions of their services have been provided at the distribution level. In its application, PG&E proposed to remedy this problem, which would increase the transportation rates of these customers by about 200%. The two customers, both facilities owned by West

Coast Gas, objected on the grounds that had they known they would be receiving large rate increases, they may have taken action to enable them to continue eligibility at the lower rate.

The Agreement would phase in higher rates to cushion the rate impact on West Coast and to provide West Coast time to "consider its options." West Coast's revenue requirement would increase by 10% a year until PG&E's next BCAP. The shortfall would be allocated to other distribution customers.

Rule 17.1 of PG&E's tariffs governs backbilling in cases where billing was in error as in the case here. It provides that, for nonresidential customers, PG&E may bill for the undercharges for a period not to exceed three years. Under the tariff, PG&E is not required to collect past liabilities where, as in this case, the billing was in error. But this particular case, backbilling would not be at issue because PG&E had no tariff offering distribution service to West Coast's wholesale operations.

Whether PG&E's agreement with West Coast is reasonable is another matter. PG&E may not unduly discriminate in favor of or against any customer. While we may permit an exception to current ratemaking practices which set forth methods for establishing distribution rates, we must have a strong justification for doing so, especially where the exception would impose ratemaking burdens on others. Here, neither West Coast nor PG&E has provided adequate policy justifications for requiring distribution customers to continue to subsidize West Coast's wholesale operations. PG&E explains that its plan to increase West Coast's rates gradually by 10% a year is an effort to avoid "rate shock" for West Coast and to give the company time to "implement an alternate plan." "Rate shock" is not and has never been a justification for excusing a single customer from rates calculated according to prevailing ratemaking policies. California utilities, including PG&E, routinely backbill customers for undercharges that occurred as a result of utility error, as permitted by their tariffs. In a recent case that breaks no new ground, the Commission found that SCE appropriately doubled the electric rate of a small residential customer after the utility had for many years billed at the wrong rate (Gildner vs. SCE, D.02-11-007). That customer was provided no opportunity to change his usage strategy before receiving his first bill at the substantially higher rate. We could cite dozens of other similar cases, both formal and informal, where PG&E backbilled a customer large amounts as a result of billing error. We are not aware of any circumstance where PG&E agreed to excuse a customer from tariffed rates going forward. It matters little that West Coast has not had time to "consider its options." West Coast has already had adequate time to "consider its options," having been informed of the error at least a year ago, prior to the date PG&E filed this application.

We are also concerned with the open-ended nature of the Agreement's provision for this subsidy. Specifically, the Agreement provides for a 10% annual increase "until a decision in PG&E's next BCAP becomes effective." We cannot determine whether this means the 10% phase-in would end and the prevailing rate would become permanent at that time, whether the parties assume the matter will be litigated again in the BCAP or whether the issuance of a BCAP order would trigger the application of the tariffed rate.

We find no justification for requiring distribution customers to shoulder the burden of West Coast's highly discounted rates and wonder why TURN and ORA would agree to such a subsidy. We reject this Agreement as unlawfully discriminatory and inequitable. We herein adopt a tariff provision for West Coast that reflects the costing methodologies we apply in such cases.

The rate increase is substantial. For West Coast's Castle facility, rates increase by 226%. For its Mather facility, rates increase by 579.4%. While these rate increases are unfortunate because of their magnitude, the amounts also suggest the subsidy that other customers have assumed on behalf of West Coast and would continue to pay if we were to adopt PG&E's proposal to increase West Coast's rates by only 10% a year for four years. PG&E may negotiate a payment plan with West Coast for remittance of future billings.

G. Updated Gas Transportation Balancing Account

PG&E's application proposes an update to PG&E's gas transportation balancing accounts every year as part of the annual True-up Advice Letter on January 1 of each year rather than in the BCAP proceeding. PG&E believes the annual true-up would provide consistent rate changes because other rate changes occur on January 1. The Agreement incorporates this proposal.

This change in the timing of reconciling balancing accounts is reasonable and does not appear to create any administrative problems, inequities or inefficiencies.

H. Other Balancing Account Modifications

PG&E proposed several minor modifications to its balancing accounts for gas services as follows.

1. Establish a new account to track revenues from the core customer charge;
2. Recover Canadian costs in the Core Pipeline Demand Charge Account instead of the Purchase Gas Account (PGA);
3. Refund the balance in the Core Subscription Phase-out Account and Core Subscription PGA to former core subscription customers; and

4. Terminate the El Paso Turned-Back Capacity Balancing Account and Noncore Brokerage Fee Account.

Only ORA commented on PG&E's proposals, supporting all of them with one exception. Instead of establishing a new account for the core customer charge, ORA would establish a subaccount of the Core Fixed Cost Account to track revenues allocated on an equal-cents-per-therm basis. The Agreement would have the Commission adopt ORA's recommendation on this item and all of the other account changes PG&E proposes, as follows:

a. Establish two subaccounts under the Core Fixed Cost Account, one for items allocated on an equal-cents-per-therm basis and another for items allocated on an equal-percentage-of-marginal-cost basis;

b. Recover Canadian costs in the Core Pipeline Demand Charge Account instead of the Purchased Gas Account (PGA);

c. Refund the balance in the Core Subscription Phase-Out Account and Core Subscription PGA to former core subscription customers; and

d. Terminate the El Paso Turned-Back Capacity Balancing Account and Noncore Brokerage Fee Account.

These changes are lawful and mostly ministerial in nature. We take no issue with them and adopt them.

I. Balancing Account Treatment for Noncore Distribution Revenues

PG&E currently is at risk for collecting noncore distribution revenues based on an adopted forecast. In this application, it proposes to eliminate this risk and receive 100% balancing account treatment for all noncore distribution revenues. PG&E explains that increased market risk and economic volatility justify this change in risk allocation.

The Agreement would adopt a compromise whereby PG&E would be at risk for only 25% of its noncore distribution revenues. Customers would assume the risk for the remaining 75%.

In its brief, PG&E addressed the expressed concerns of the assigned Administrative Law Judge (ALJ) in this proceeding that the matter was pending before the Commission in another proceeding, Rulemaking (R.) 04-01-025, the Gas Capacity Rulemaking. PG&E states that D.03-12-061 invited PG&E to raise the issue of balancing account treatment for noncore distribution revenues in its subsequent BCAP. This proceeding is the subsequent BCAP. PG&E's brief also observes the scope of R.04-01-025 involves transmission capacity, not distribution facilities or rates.

We agree with PG&E that R.04-01-025 is unlikely to address the issue of gas distribution rates or incentives. We also concur that D.03-12-061 anticipated that PG&E could propose a change to noncore distribution balancing accounts in a subsequent BCAP application. This is that proceeding.

PG&E makes a reasonable case that its risk for noncore distribution revenues should be limited. PG&E has little control over noncore throughput and markets have become more volatile in recent years. While these circumstances might not alone be adequate justification for shifting risk to customers, the proposal before us splits the risk between PG&E and its customers by imposing 25% of liability for noncore throughput on PG&E. This is a reasonable compromise and we adopt it.

4. Agreement on Master Meter Discounts

The Commission has anticipated implementing a discount for master meter customers in recognition that the costs of service to master meter customers are lower than the utility would incur if it were to bill individual customers. In D.04-11-033, the Commission required that "the discount provided to mobilehome park homeowners (MHP) pursuant to Pub. Util. Code § 739.5(a) "shall be set at the average cost that the electrical or natural gas utility would have incurred in providing comparable services to the MHP tenant directly, which is avoided when the MHP is submetered." The Commission also found that the calculation of the discount may be made on the basis of a random sample or using a marginal cost analysis.

PG&E TURN and WMA, representing mobile home parks, reached agreement on all related issues as follows:

1. The base master meter discount for gas schedule GT shall be fixed at $0.39 per space per day until the next BCAP.
2. The diversity benefit adjustment shall be fixed at $0.034 per space per day until the next BCAP.
3. The base master meter discount for gas schedule GS (multi-family service for other than mobile home parks) shall be fixed at $0.199 per unit per day, with a diversity benefit adjustment of $0.022 per unit per day until the next BCAP.
4. PG&E will update the data used to calculate the diversity benefit adjustment in its next BCAP, or if the BCAP is delayed, in another rate design proceeding in the next two years.

The settlement rate is based on the range of values proposed by TURN, Western Mobilehome Association (WMA), and PG&E and using marginal cost methods, $.35 at the low end and $.49 at the high end.

We find that the settlement on these issues is consistent with § 739.5(a) and presents a reasonable compromise between parties representing the interests of residential customers and mobile home park owners. We adopt it herein and state our commitment to revisiting this issue depending on PG&E's updated data.

5. Agreement on Natural Gas Vehicle Rates

Clean Energy opposed the natural gas vehicle compression rates PG&E proposed in this proceeding, arguing that they are inappropriately based on marginal costs rather than fully allocated costs. Clean Energy provides natural gas vehicle fueling services and alleges it cannot compete with PG&E in this market because it believes PG&E's compression rates are effectively subsidized.

After hearings were completed, Clean Energy and PG&E settled the Natural Gas Vehicle (NGV) compression rate issues and filed a settlement on March 17, 2005. The settlement agreement would increase PG&E's compression rate for compressed natural gas (CNG) vehicles to recognize allocated costs. The rate would increase by $0.15 on the implementation date of this BCAP, and escalate by $0.03 per year beginning January 1, 2006 and each year thereafter until new BCAP rates are put into effect. It also calls for the rate for customer premises compression services to be fully deaveraged from the rates of other customers upon implementation of this BCAP. The settlement also requires PG&E to update its study of the cost to provide compression service for CNG vehicles for review in PG&E's next BCAP. The changes to the compression charges and the deaveraging of core experimental uncompressed NGV1 service will increase costs allocated to other customers of $337,000 - about a 0.01% increase (one one-hundredth of a percent), or about one penny on an average residential customer's bill.

The settlement is a reasonable compromise that accommodates both parties' competing concerns at a small cost to other ratepayers, and provides the means to update the compression cost study and rate in the next BCAP.

6. Allocation of CARE Surcharge Costs

The CARE program provides discounted rates to low-income energy customers. The number of subscribers to the program has increased substantially in recent years as a result of the energy crisis, more aggressive utility marketing and easier enrollment procedures. The program cost for PG&E was $10.2 million in 2000 and is estimated to be $80 million in 2005. Adding to this an undercollection from 2004, the total revenue requirement for the gas CARE program is $99 million or about $.023 per therm if allocated equally to all customers. The Commission has traditionally allocated these costs to all customer classes on an equal-cents-per-therm basis.

PG&E proposes to change the allocation according to "equal-percent-of-transportation-revenue." Applying this methodology would allocate a much greater share of costs to residential customers - about $21 million -- increasing the average residential gas bill by $.74. Industrial and commercial customer bills would fall proportionately. PG&E advocates for this change on the basis that the Commission should implement rate changes to reduce business costs and make California more attractive to business. PG&E believes this approach is fair because all residential customers could potentially benefit from the rate discounts, whereas the rate is not available to larger customers.

CMA supports PG&E's proposal. It argues that the increased revenue requirement means that the CARE portion of the transmission rate has increased from about 9% of transmission rates in January 2001 to 55% of transmission rates in 2005 compared to 7% of the residential baseline rate. Because the rate is spread over many fewer transmission customers than residential customers, the proportional share allocated to transmission customers is much larger. The average transmission level customer would pay $76,800 in CARE costs in 2005 if the costs were to be allocated on an equal cents per therm basis.

TURN and ORA oppose any change in CARE cost allocation. TURN observes that the Commission has consistently found that the program should be supported by all customers and argues that "non-eligible, residential customers are no more responsible for the costs or enjoy the benefits of the CARE program than noncore customers…." ORA rejects PG&E and CMA's comparison of residential bills with transmission bills, observing that isolating transmission rates for the comparison skews the analysis. ORA points out that when the commodity cost of gas is included in the industrial customer equation - as it is for residential customers - the burden of the CARE program is not disproportionate. To provide perspective, ORA observes that transmission level customers have experienced as much as a $.17 per month price increase for gas, compared to the total CARE rate component of $.023. ORA is not convinced that PG&E has demonstrated any connection between the CARE component in transmission rates and hardship by local businesses.

As a threshold matter, we are sympathetic to concerns over the costs incurred by California businesses especially during this difficult economic period. On the other hand, we are equally concerned with the plight of families and individuals, many of whom have seen their salaries fall while the cost of living increases. No party has presented any evidence to suggest that the CARE rate component has caused businesses to fail or relocate. To the contrary, TURN shows that California businesses failed prior to the increase in the CARE rate, when gas rates spiked and the economy slid into recession in 2001. We are not convinced by PG&E's claim that CARE program benefits inure entirely to residential customers. We believe that all businesses and individuals benefit from the economic welfare of the greater community. Moreover, we would not assume that all residential customers are potentially CARE customers any more than we would assume that all business customers may potentially fail in the near term.

The analysis CMA presents using transmission rates alone overstates the impact of CARE rates on large customers and is in fact deceptive. CMA improperly compares large customer transmission billings with total bills of residential customers. The CARE rate component is not 55% of a transmission customer's total bill, only the transmission portion, which is a small part of most industrial customer bills. Assuming a gas price of $.60 cents per therm, the average CARE rate component of transmission customer bills is 3.5%, half of the allocation to residential customer bills, which is closer to 7%.

PG&E proposes to change the CARE allocation effective January 1, 2006, when its public goods charge balancing accounts will be reconciled in rates. The matter is therefore not urgent. Although we do not find evidence that the CARE rate is responsible for large customer failures or flight to other states, we are interested in considering more fully how CARE rates should be allocated to different customer classes. This order suspends a final resolution of this matter and we intend to address CARE cost allocation in this proceeding by the end of 2005.

7. Allocation and Ratemaking Treatment of SGIP Costs

The Commission implements the SGIP, an incentive program to promote the development of self-generation facilities, such as microturbines, wind turbines, photovoltaic, and fuel cells installed on the customer's side of the meter and that provide a portion or all of the customer's electric load. Although the program affects electric customers primarily, its costs are allocated to both gas and electric customers.

PG&E, TURN and ORA propose that the SGIP costs be allocated on an equal cents per therm basis. PG&E would excuse wholesale customers from assuming a share of the costs because they are excluded from participating in the SGIP program. TURN and ORA observe that the Commission has consistently allocated the costs of environmental programs, such as the SGI.

CCC/CMTA proposes the Commission allocate SGIP costs using the same allocators its uses for energy efficiency programs. First CCC/CMTA argues that allocation of SGIP costs to electric generator gas rates would result in electric consumers paying twice for SGIP costs, once in their gas rates and again in the cost of gas-fired electric power. CCC/CMTA observes that the Commission has excluded EGs from paying for the Low Income Ratepayers Assistance Program because of the potential for double payment by electric customers. Such a double payment would, according to CCC/CMTA, unreasonably "tip the competitive balance between gas-fired and non-gas fired EGs in favor of the latter." CCC/CMTA's allocation proposal would exclude EGs from the allocation. NCGC supports CCC/CMTA's proposal, offering similar argument.

PG&E's allocation proposal does not result in double recovery. It does, however, require EGs to, in effect, pay twice for the SGIP program. We see no inequity in this in that the Commission could have logically allocated all SGIP costs to electric customers. Consistent with our view that all customers should pay for program that provide environmental benefits, we include wholesale customers in the allocation of SGIP costs as well as EG customers, and adopt PG&E's proposal to allocate the costs on an equal cents per therm basis.

We also address NCGC's objection to PG&E's proposal to recover SGIP costs through a balancing account rather than a memorandum account. NCGC states PG&E did not explicitly propose this change in recovering SGIP funds but its witness disclosed PG&E's intent to make this ratemaking change if the Commission were to adopt its proposal to update gas balancing accounts annually. Currently, PG&E records SGIP costs to a memorandum account and asks to have related expenditures included in rates by way of advice letters. NCGC opposes this change in ratemaking, observing that the Commission is considering issues related to the SGIP in its rulemaking on distributed generation, R.04-03-017. We agree with NCGC that this is not the time or venue for ratemaking change to the SGIP accounts. PG&E should modify its plan to transfer SGIP funds to a subaccount of the Noncore Customer Class Charge Account (NCA).

8. Calculation of Marginal Costs

A. Replacement Adder

The Commission has allocated PG&E's gas costs between customer classes on the basis of long run marginal costs, which are typically described as those costs incurred in the long run to produce an additional unit of output. PG&E proposes to change the way it calculates marginal customer costs for the purpose of allocating costs among customer classes. Specifically, it would eliminate the "replacement cost adder" from the equation. Replacement costs are those costs anticipated to change out gas facilities that are worn, out-of-date or otherwise in need of replacement. The Commission required PG&E to include those costs in its long run marginal cost calculation finding that doing so "is consistent with marginal cost economic theory" (D.95-12-053, *mimeo*, at 22) and that "in the long run, all costs are variable and there is an opportunity cost to not replacing the existing system." (D.97-04-082, *mimeo*, pp 47-48.)

PG&E states it is the only energy utility for which a replacement cost adder is required. It states it cannot avoid replacement of gas pipeline facilities when demand falls and that its pipeline replacement program is related to facility deterioration, not throughput.

ORA and TURN object to changing the marginal cost calculation by removing the replacement cost adder. TURN argues that a business must price its products according to its anticipated costs, among them, those to maintain its infrastructure. TURN also observes that the US Department of Transportation has found that gas velocity (that is, throughput) affects the rate of pipeline corrosion.

Economic literature apparently does not explicitly address the issue of replacement costs as an element of long run marginal costs. A casual survey of trained economists would (and did) present competing views of this issue. While there may be logical arguments on both sides, the burden of making a case to change Commission policy is on the proponent of change. PG&E did not make a convincing case that its methodology was superior to the existing methodology, whether from the standpoint of theory, equity or common sense. Accordingly, we do not change the methodology at this time. We adopt ORA's estimate of replacement costs.

B. Hookup Facilities

The Commission has traditionally calculated the marginal cost of customer interconnection or "hook up" by using a method PG&E calls "new customer only." This method assumes a one-time charge for new facilities in the marginal cost calculation. The Commission has found that this method reflects the circumstances in gas plant that customer hook up equipment cannot be used for any purpose except to serve the existing customer.

CCC/CMTA proposes the Commission use a "mortgage method" to annualize the cost of hookup facilities. This method would apply a long-term mortgage financing rate to all facilities rather than assigning value in a lump sum only to new facilities. CCC/CMTA states this method is conceptually appropriate because gas facilities are associated with the customer's premises, which would be financed with a commercial mortgage. Using this method would track the economic life of the facilities, which the current methodology does not do. The existing methodology, according to CCC/CMTA, inaccurately assigns costs to the customers because the costs of new facilities are spread equally to customers with new and existing facilities. CCC/CMTA proposes that its methodology sends more appropriate price signals in competitive markets. It would do so by assuming that in a competitive market, customers could purchase their own facilities and finance them with a 30-year mortgage at a specified rate.

PG&E and TURN object to the proposal on the basis that CCC/CMTA's justifications for adopting the mortgage method simply reiterate those the Commission has rejected in the past. WMA proposes a "rental" method that is conceptually similar to CCC/CMTA's proposal and which the Commission has also rejected in past orders.

CCC/CMTA makes some reasonable arguments for its proposal. On the other hand, we have consistently found that the existing methodology reasonably allocates costs to those customer groups who install the most new hook ups. We respond to concern that the existing methodology does not recognize the value of existing hook-ups by reiterating our view that existing hook-ups have little if any market value. As PG&E observes, replacement of related facilities is also included in the calculation. We will retain the existing method of recognizing interconnection costs in the marginal customer cost calculation.

C. Miscellaneous Marginal Cost Issues

ORA and TURN made several minor suggestions with regard to calculating marginal costs as follows:

1. ORA would use the period 1999-2003 instead of PG&E's 1989-2003 period to establish service line lengths. PG&E agrees that the more recent years' data is more accurate and we adopt it.
2. ORA would use the 2000-2003 period instead of PG&E's 2002 adjusted recorded data to estimate the Administrative and General Loading Factor. PG&E would use the more recent number which reflects a trend of higher spending in this area. We adopt PG&E's estimate as more accurate than ORA's.
3. ORA recommends a corrected Distribution General Plant Loading Factor of 25. 57% rather than PG&E's 24.93% to reflect the removal of transmission plant that should have been excluded. PG&E agrees with ORA's adjustment and we adopt it.
4. ORA recommends a Customer-related Common and General Plant Loading Factor of 5.54% based on most recent 2002 recorded data rather than PG&E's estimate of 5.48%. We apply PG&E's most recent data, consistent with our treatment of the A&G Loading Factor.
5. PG&E and ORA agree that service line lengths for smallest customers should be based on data from July 1998 to 2003. We adopt their recommendation to use this period for estimating small customer service line lengths.

6. TURN and PG&E agree that the design cost for individual customers should be $43 rather than $101 originally proposed by PG&E. We adopt this modification to PG&E's estimate of design costs for individual customers.
7. ORA recommends a $1,255 marginal investment cost for the forecast distribution investment plan instead of PG&E's recommended $1,232. ORA's estimate is more recent than PG&E's and we therefore adopt it.

9. Categorization and Need for Hearings

In Resolution ALJ 176-3137 dated August 19, 2004, the Commission preliminarily categorized this application as ratesetting, and preliminarily determined that hearings were necessary. No party protested the categorization and it is confirmed here.

10. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties on April 26, 2005 in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure.

11. Assignment of Proceeding

Geoffrey Brown is the assigned commissioner and ALJ Kim Malcolm is the principal hearing officer in this proceeding.

Findings of Fact

1. ORA, TURN, and PG&E filed an agreement that resolves several ratemaking, rate design and allocation issues. The agreement is identified in the record as Exhibit 29 and no party protested any of its elements.

2. A $3 minimum monthly transportation charge for residential customers would not create hardship for customers and recognizes that PG&E incurs costs even when a customer does not use any gas commodity.

3. Including the month of April in the summer gas baseline and setting the baseline differential at 20% between Tier 1 and Tier 2 when the transportation difference is no less than 1.6 would ease rate impacts during cold months for customers who use gas in the second tier.

4. Accelerating the pace of deaveraging beyond 10% a year between residential and commercial customers would increase rates too much.

5. Because it limits rate increases and bill complexity, adding two rate tiers for small commercial customers is a reasonable compromise to combining small and large commercial customer classes into a single class.

6. A total gas throughput forecast of 742,545 MDth / year and electric generation throughput forecast of 264,913 MDth / year reasonably recognizes gas customer demand for the test period.

7. PG&E erroneously billed two facilities of West Coast Gas Distribution Company as transportation level customers, although they are distribution level customers. PG&E has provided no justification for its proposal to have gas distribution customers continue to subsidize the rates of West Coast Gas.

8. PG&E, WMA and TURN filed an agreement resolving issues related to master meter discounts for mobile home park owners, which is consistent with past Commission statements of how the discounts should be structured. No party protested the agreement.

9. PG&E's general proposal to update its gas transportation balancing accounts every year as part of the annual "true-up" advice letter for rates effective January 1 of each year would not create any administrative problems or harm customers.

10. Splitting the liability for noncore distribution revenue requirement forecasts between PG&E and ratepayers is reasonable in light of market volatility

and considering that it is unlikely to create any unintended consequences with regard to PG&E's system management.

11. PG&E and Clean Energy agree that (1) PG&E's Natural Gas Vehicle Compression rate should increase by $.0.15 and escalate by $0.03 beginning January 1, 2006 and each year thereafter until the next BCAP rates become effective, (2) customer compression services be fully deaveraged, and (3) PG&E should update its cost study for review in PG&E's next BCAP. No party opposes this settlement, which would increase rates to recognize PG&E's allocated costs and thereby reduce the likelihood that PG&E's compression rates are anti-competitive.

12. CARE program benefits are not limited to residential customers and there is no evidence to support the contention that CARE surcharges have caused businesses to fail. The Commission need not address the issue of CARE allocations in this order because PG&E proposes to change the allocation effective January 1, 2006.

13. PG&E's proposal to allocate SGIP costs to all customers on an equal-cents-per-therm basis is reasonable and consistent with the Commission's policy to spread the costs of environmental programs to all customers.

14. Economic literature does not resolve whether replacement costs are appropriately included in long run marginal cost calculations.

15. The Commission has included replacement costs in the gas marginal customer cost calculation and the record in this proceeding does not present adequate justification for modifying this element of the calculation.

16. CCC/CMTA proposes a variation of a way to calculate the "hook-up" portion of marginal customer costs that it refers to as the "mortgage method"

that is comparable to the "rental" method the Commission has rejected in the past.

17. CCC / CMTA has not adequately justified changing the calculation of that element of marginal customer costs referred to as "hook-up costs."

Conclusions of Law

1. The agreement submitted by PG&E, ORA and TURN and identified in this proceeding as Exhibit 29 is consistent with the law, the record of the proceeding and otherwise reasonable except to the extent set forth herein.

2. PG&E may not relieve a customer from liability on the basis that it wishes to protect the customer from "rate shock" or provide time for the customer to "consider its options." PG&E's proposal to relieve West Coast Gas of appropriate rates is discriminatory and unjustified.

3. West Coast should be subject to tariffed rates that are developed consistent with pricing methodologies for wholesale distribution rates. PG&E should be ordered to bill West Coast Gas the adopted tariffed rates for distribution service beginning with rates effective the date of this order.

4. The agreement submitted by PG&E, WMA and TURN resolving master meter discounts for mobile home park owners is reasonable and consistent with § 739.5.

5. The Commission should defer to a later date the issue of whether to change the allocation of $21 million of CARE costs to residential rates and to resolve the matter prior to January 1, 2006.

6. PG&E should be required to allocate SGIP costs to all customer classes on an equal cents per therm basis.

7. The calculation of marginal customer costs for gas service should continue to include a value recognizing replacement costs of gas facilities.

8. The gas throughput forecasts proposed by PG&E, TURN and ORA in Exhibit 29 should be adopted.

9. PG&E's risk for noncore gas distribution throughput should be set at 25% of revenues, as proposed by PG&E, TURN and ORA in Exhibit 29.

10. The provisions of the agreement between PG&E and Clean Energy addressing PG&E's natural gas vehicle compression charges should be adopted.

11. The minor changes to marginal costs described in Section 8.c of this decision should be adopted.

INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company shall file, no later than 30 days after the effective date of this order, revised tariff schedules which implement the adopted changes shown in Appendix A. The revised tariff schedules shall comply with General Order 96-A and shall apply to service rendered on or after their effective date of July 1, 2005. The tariffs shall not include any modifications except those expressly authorized by this decision.

2. PG&E's subject application is granted to the extent expressly set forth herein.

3. The Agreement between TURN, PG&E and ORA identified as Exhibit 29 is approved except to the extent set forth herein.

4. The Agreement between PG&E and Clean Energy resolving natural gas compression charges is approved.

5. The Agreement between PG&E, TURN and WMA addressing master meter discounts for mobile home park owners is approved.

6. PG&E shall apply the rate approved in this order to West Coast distribution services. PG&E shall not offer West Coast any service at any rate except those included in PG&E's tariffs.

7. Application 04-07-044 will remain open to resolve the issue of the allocation of $21 million in costs related to the CARE program.

This order is effective today.

Dated ____________________, at San Francisco, California.

APPENDIX A TO Malcolm A0407044